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The Eight Best H2S Removal Methods in Federal Waters, Offshore California

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Abstract

In Federal waters offshore California, there are currently many desulfurization techniques implemented on 23 platforms to address different H_2S levels as a function of daily production rates. This paper describes the individual effectiveness by design criteria, repair history, and performance under overload. It is intended to help future platform operators in the selection of a gas sweetening technique based on raw gas volume and H_2S contamination. It also describes two methods applicable in other offshore areas, but abandoned recently in the Pacific Federal waters due to strict air quality restrictions and costly emission source-offset requirements.

Introduction

This is the first attempt to evaluate the current H_2S removal technologies in offshore California. (See table 1 on platform characteristics and the H_2S contamination range of 3 ppm - 18,000 ppm). The criteria for evaluation are: removal efficiency, safety, and economics. The author noticed that low H_2S levels can be treated efficiently with regenerable slurry methods, while high gas contamination may need robust, amine type processes. The paper also includes an example for total pre-flare sour gas sweetening. The summary contains a suggested selection processes for the right technology.

<u>1. Platform Elly, Beta Field (Shell/ CalResources, LLC.):</u>

After 6 years of water reinjection of up to 20,000 BPD, the underground chemical reaction yielded increasing H_2S content in produced gas. In 1988, when hydrogen sulfide levels reached 14 ppm, Shell Western Exploration & Production, Inc. (SWEPI) initiated the Petrolite SX-600 injection for fuel gas sweetening. In 1990, H_2S contamination in raw gas reached 19 ppm, while in 1992 routinely exceeded 28 ppm, causing the sweetened fuel gas readings to exceed the 3 ppm maximum admissible H_2S level posted by the South Coast Air Quality Management District[1] in the Los Angeles air basin. Excursion data triggered by system dynamics show that during the sweetening process part of the mercaptans became trapped in the oil phase, causing instrumental readings of 1-7 ppm H_2S in the sweet fuel gas for turbines and heater treaters:

H_2S + SX-600 <===> (mercaptans + gas + H_2S)

At this point, SWEPI decided to implement the SulfaTreat technology to comply with county, State, and Federal requirements for the Pacific Outer Continental Shelf (Pacific OCS).

The concept consists of two beds operating in series, while one is approaching the allowable depletion level the other is replaced and kept in stand-by mode to correct excessive volume fluctuations during kicks in the wells. The catalyst is non-regenerable; it must be barged offshore. The end product is classified environmentally friendly by the EPA and by California Title 22 criteria, therefore, it can be disposed of in local landfills. The piping, skids, accessories, and the two catalytic beds weigh 90,000 lbs. The advantages of SulfaTreat process are: (1.) No toxic gases are generated. (2.) No oral or dermal reactions. (3.) It employs a non-hazardous material (flammability, reactivity, ignitability, corrosivity). (4.) It dos not foam.

<u>Design Parameters for Platform Elly:</u>

Maximum H_2S:	60 ppm.
Requirements:	80% H_2S; 100% mercaptans.
Fuel gas quality in 1996:	< 2 ppm H_2S.
Treated gas volume:	1,600 MCFD
Pollution in 1990:	12 tons of SO_X.

NOTE: SulfaTreat is a dry, free flowing, nonpyrophoric material for batch-type processes. It is more efficient and costs less per pound than either ironsponge (20%) or Sulfa-Check methods. It is not affected by liquid hydrocarbon poisoning, low ph, or methanol contamination (a poisoned catalytic bed would be inoperative). It is not a slurry, and does not foam; it is sold commercially in 50 lb bags.

2. OS&T Storage Vessel (Exxon Co., U.S.A.)

The former Offshore Storage and Transfer Unit (OS&T), a floating facility served as first stage process and gas sweetener unit for the nearby Platform Hondo. The H_2S concentration averaged 9,000 ppm in 1992. Due to air quality restrictions, produced gas in Santa Barbara County[2] had to be sweetened to less than 50 ppm for the OS&T turbine generators that provided electricity for both OS&T and Platform Hondo. Increasing H_2S concentrations and gas volumes became a challenge for the operator because Platform Hondo was not designed for sulfur removal and the two new platforms nearby (Harmony and Heritage) were still under construction. The investment had to be modest because the decommissioning date for the OS&T was April 1994.

Historic background: Exxon started the OS&T operation in 1981 with an amine based Sulfur Recovery Unit (SRU) and reinjecting the sour gas with produced water. By late 1987, the SRU was running at full capacity. Since the water reinjection well could not take more than 50 MCFD of sour gas mixed with produced water, the additional mass of acid gases (8,000- 18,000 ppm of H_2S) from system overflows had to be flared, causing massive air quality liabilities. In 1988 SO_X emissions from flaring alone reached 167 tons/year, which Exxon could not “offset” by controlling equal mass of onshore sulfurous emission sources, which are hard to find, and thus very expensive in Santa Barbara County.

To mitigate sulfur emissions from flaring, Exxon had chosen the Sulfa-Check concept, saving a lot on air emission offsets. Excess acid gas from the amine regenerator and from the oil-gas separators to the fuel gas lines had to be processed. Acid gas flow from the regenerator consisted of 82% CO_2 and 18% H_2S, up to 97 MCFD. Sour gas was first scrubbed of hydrocarbons, then preheated before entering two, 500 gallon Sulfa-Check towers. It bubbled through the two Sulfa-Check towers where the reactions took place. The wet exit stream contained 99.7% CO_2 and 0.3% H_2S, producing a nonhazardous slurry composed of water, elemental sulfur and sodium bicarbonate solids. The gas was scrubbed of liquids, before going to the flare. The unit could handle large gas volume fluctuations beyond the normal capacity of the original amine unit.

Design parameters for the OS&T:

Maximum Capacity:	1.6 LT H_2S/day.
H_2S, untreated gas to flare:	8.5 KCFPD.
H_2S, treated gas to flare:	0.1 KCFPD.
H_2S removed by chemical:	8.4 KCFPD.
Max. acid gas in reinj. water:	50 KCFPD.
Yearly max. design capacity:	205 t/year.

The chemical was transported in 2,000 gallon U.S. Coast Guard tote tanks twice a week. Solid waste was dewatered, bagged and transported to disposal facility. OS&T was generating 2,000 lbs. of nonhazardous solids per day during system operations. It ceased operating in March 1994.

3. Platform Harmony (Exxon Co., U.S.A.)

On this platform, by County regulations, the fuel gas must contain less than 5 ppm of H_2S, the desulfurized diesel fuel must have less than 0.5% of sulfur by weight, and all major engine activities had to be electrified. Sulfur emissions from flaring can not exceed 30 ppmv (ppm by volume), all flares are smokeless; even the pilot/base-flare gas is sweetened gas.

The platform is equipped with a clean fuel gas generation unit for the major functions. The unit uses a solution of 50% methyldiethanolamine (MDEA) in deionized water. Sour produced gas of 4,000-8,000 ppm H_2S bubbles up through a contactor tower. Sweet gas is routed into the fuel gas system. The acid gas removed in the amine regenerator is recycled to the sales line compressor.

One unique feature is the way the amine unit is designed because this platform does not remove elemental sulfur. The concentrated acid gas stream flows into an amine reflux condenser where steam is condensed as water and “dry” acid gas is recovered. “Dry” acid gas is recombined with produced gas in the sales line (concentrated acid gas is never vented into the atmosphere). Amine and water are recombined, filtered, and cooled; the regenerated amine is pumped back to the contactor tower for reuse. In contrast with a similar concept implemented on Platform Heritage, on this platform the amine still-column and the reflux accumulator are kept separately in two different vessels to enhance process stability and safety. The clean fuel gas never reaches the maximum limit of 30 ppmv H_2S due to the built-in safety coefficient. At the top of the contactor tower, gas leaving the vertical trays contains less than 3 ppmv of H_2S.

Design parameters for Platform Harmony:

a, Max. Capacity:	1.5 MMSCFD.
Raw gas H_2S:	1,500 ppmv.
b. Minimum capacity:	0.75 MMSCFD.
Raw gas H_2S:	8,000 ppmv.
Sweet fuel gas:	<30 ppmv H_2S.

Flare purge + pilot clean fuel: 445 SCFHr.
Central process heater: 650,000 SCFHr.
Daily MDEA losses: 0.5 pint/day.

Note: In spite of the massive daily fuel gas demand, the system is very reliable. There is no need to store or dispose of waste products, and there is no fire/explosion hazard either. Acid gas is pumped into the sales line and processed safely onshore. There is no SRU on the platform.

4. Platform Heritage (Exxon Co., U.S.A.)

The production and processing are computer optimized; every function is electrified. Electricity is supplied from onshore via 7 mile submarine cable. The only external combustion equipment is the Central Process Heater. Exxon opted for an amine fuel gas treatment facility to generate clean fuel for the platform. A solution of 50% methyldiethanolamine (MDEA) in deionized water flows through a contactor tower to treat up to 1.58 MMSCFD gas of 2.99% H_2S.

Sour gas along vertical trays bubbles through the amine solution, exiting at the top. The sweet gas (less to 30 ppmv H_2S) is heated and routed to the fuel gas manifold. The exiting amine stream is rich in absorbed acid gases, and it is pumped first to a flash tank, next into the amine still column to remove acid gases by steam, generated in the amine reboiler. Water is condensed from the concentrated acid gas stream in the amine reflux condenser. “Dry” acid gas is recombined with produced gas to be reinjected into the producing formation to serve the reservoir pressure maintenance program. Amine and water are recombined, filtered, and cooled. The regenerated amine then is sent back to the contactor tower for reuse. Concentrated acid gas is never vented into the atmosphere. To optimize the process, the amine still column and the reflux accumulator are within the same vessel on this platform. The amine loss (and the refill) is approximately one half pint per day.

MDEA is an environmentally friendly chemical. It is not on the list of hazardous substances of the Clean Water Act (40 CFR 116) or on the CERCLA list (40 CFR 302), or under SARA Title III (40 CFR 355) as an “extremely hazardous substance”. It is not listed on the DOT Haz-Mat transportation list either. Exxon stores MDEA on Platform Heritage in accordance with MSDS recommendations. The platform reinjects produced gas for reservoir pressure maintenance.

Design parameters for Platform Heritage:

Capacity: 1.58 MMSCFD.
H_2S gas concentration: 2,990 ppm.
Sweet fuel gas: <30 ppmv H_2S.
Daily MDEA losses: 0.5 pint/day.
Reinjection in April ’96: 35 MMCFD.
Clean fule, flare purge & pilot : 445 scf/hr
Central process heater: 650,000 scf/hr.

There are three remarkable features on this platform: (1.) It requires very little maintenance and raw materials. (2.) There is no SRU on it; and (3.) There is no waste material disposal.

5. Platform Harvest (Chevron U.S.A. Production Co.)

The platform burns low sulfur diesel fuel in its three cranes, and uses sweetened produced gas in its five water injected turbine-generators and three turbine-compressors (5,000 HP each). These turbines provide on-site electricity for all platform functions including the water desalinization plant that generates highly purified water for turbine injection through a quad-distillation process enhanced by resin treatment (NaCl < 0.04 ppm), during special operations. It could also run on diesel fuel. Platform Harvest’s capacities are: 60,000 BOPD; 50,000 BWPD; and 50 MM SCFD gas.

This platform measured the highest H_2S concentration in produced gas stream in the Pacific OCS at 27,000 ppmv. To dilute it, wells are selectively perforated and commingled to maintain average H_2S contamination below 14,000 ppmv. To achieve fuel gas criteria, produced gas is sweetened in the amine based fuel gas Treatment and Regeneration system. The amine unit employs diethanolglycolamine (DGA) to remove H_2S and CO_2 from the production gas. Volume for gas sweetening is provided from downstream of the dehydration and refrigeration systems. The sour gas enters the amine contactor tower and is sweetened to less than 50 ppmv H_2S. In practice, the fuel gas is treated to near zero ppmv H_2S.

The amine contactor contains three stacked sections a total height of 40 ft. Rich amine flows from the contactor to the amine flash tank where dissolved hydrocarbons are removed by flashing at reduced pressure. Rich amine is regenerated in the amine regenerator, then cooled, filtered, and returned for reuse into the amine contactor. To make the platform more energy efficient, Texaco implemented a giant waste heat recovery unit based on the exhaust heat from 8 turbines.

Flare purge and pilot light systems are running exclusively on sweetened gas. The low pressure purge gas runs on 1,000 SCFHr, the high pressure purge line base rate is 1,250 SCFHr while the pilot light gas flow rate is 100 SCFHr.

Design parameters for Platform Harvest:

Maximum gas usage in turbines: 7.55 MMSCFD.
Maximum H_2S in sweet gas: 50 ppmv (as total sulfur).
Base flare and pilot light: 5,640 SCFD.
Desulfurization capacity (min.): 9.0 MMSCFD.
Desulfurization capacity (max.): 17 MMSCFD.
Max. H_2S in sales gas: < 7,600 ppmv of H_2S.

Texaco's choice to use the high performance DGA amine unit is justified. The extremely wide fluctuations in H_2S concentrations (8,000-27,000 ppm), frequent gas kicks in the wells, high daily production volumes, and high fuel gas demand by the turbines do not leave room for mechanical breakdowns. Any other type of process would require either more maintenance, waste disposal or batch-bed related storage problems. The platform does not process elemental sulfur, but reinjects acid gases into the sales line.

6. Platform Hermosa (Chevron U.S.A. Prod. , Co.)

The operator needs were: (1.) To handle large scale H_2S fluctuations; (2.) Removal of both H_2S and CO_2; (3.) Reliable technology; (4.) Easy maintenance/repair; and (5.) No elemental sulfur product. This platform produces into the pipeline coming from Platform Harvest to the shore. Sulfur removal takes place onshore. It is electrified, without onshore cable connection, it generates its own electricity in 5 turbine generators. Four turbines are water injected, the fifth is SoloNox type, all in gas fuel mode, except during special operations. The extremely high purification of injected water has been achieved by reversed osmosis, since 1989. When load fluctuations are expected, i.e., during drilling, one turbine is put under high load while two others are running in stand-by mode.

Gas for desulfurization is taken from the compressor system upstream from the sales line. The raw gas H_2S content is between 6,000 - 14,000 ppmv. Removal efficiency[2] must be at least 239 ppmv (15 gr/100 scf) in turbines and 50 ppm for the purging of pig receivers, pilot light, and base flare. Chevron chose the DEA Amine Contactor concept to remove both H_2S and CO_2 from produced gas. Flare minimization plan is in effect, only smokeless flare is allowed.

The sour gas first enters the 40 ft amine contactor. Next, the rich amine flows from the contactor to the amine flash tank where dissolved hydrocarbons are removed by flashing at reduced pressure. At the end, rich amine is regenerated in the amine regenerator, cooled, filtered and returned to the amine contactor. Sweet gas is directed into the feed line for onboard engines and to the feed line for high-pressure and low-pressure (HP/LP) scrubbers, base flare and flare pilot lines.

Design parameters for Platform Hermosa:

Pilot flare and purge flare rate: 100 + 1,000 = 1,100 scfh.
Maximum flare rate: 32.74 MSCF/yr.
Flare gas max. H_2S: 50 ppmv.
Total flare sulfur emissions: 53.68 t/yr.
Platform's sulfur emission: < 73 t/yr.

Platform Hermosa averaged 6,300 BOPD and 6,500 MSCFD in 1996. Had Chevron chosen the same concept that is on Platform Harvest, the project would have been very expensive and oversized for this volume of production. (Platform Harvest's daily production was between 15,000 and 24,000 BOPD in 1996). The most important factor in the technology selection was the ability to cope with the fluctuating H_2S content. (Platform Hermosa does not process sulfur on the platform.)

7. Platforms Gail & Grace (Chevron U.S.A. Prod., Co.):

The operator's design criteria were: (1.) "Regenerative" desulfurization; (2.) No toxic waste or storage of chemicals. (3.) Small footprint; (4.) Twice the efficiency of the original unit on Platform Grace. This is the typical example of a Pacific OCS project, that has been accepted in 1979, and rejected in 1994 due to stricter air quality regulations in Ventura County[2].

The old Stretford Sulfur Recovery Unit (Claus type), or SRU, installed on Platform Grace in 1980 could not meet the strict air quality standards in the 1990s. The resulting elemental sulfur contained a trace of vanadium from the chemical process, therefore Chevron had to dispose of it (as toxic waste) in sealed containers into designated toxic dumps. Due to the increasing produced gas volume and its growing H_2S content, the SRU could not sweeten the 8,000 ppm contamination below 289 ppm for turbines, heater-treaters, pilot and base flare.

When the platforms had to be re-permitted in 1994, Chevron decided to abandon the Stretford Unit, install a single, oversized SulferOx Unit on Platform Gail to supply both platforms with clean fuel gas. Platform Gail's production made this unit the better choice for the operator. SulferOx technique was chosen to reduce the 4,000-8,000 ppmv H_2S contamination level to less than 300 ppmv measured as SO_X in exhaust, and below 10 ppmv (as H_2S) at any point of discharge. Due to the Clean Air Act of 1990, only low-sulfur "Clean Fuel Gas" can be burned in heater treaters, turbines, flare pilot light/base flare in the Pacific OCS.

The SulferOx Unit is a regenerative concept that meets the above mentioned design criteria. It utilizes a nonhazardous aqueous iron-based liquid reduction/oxidation chemistry to convert H_2S gas into elemental sulfur, which is filtered from the regenerative solution and sold (or disposed of as a nonhazardous waste). The main advantages of this technology compared to either a Classic Amine/Claus, or an Amine/SelectOx unit (membrane H_2S removal) are: (1.) The end product can be sold commercially instead of paying for toxic disposal; and (2.) The SulferOx technology does not produce an acid gas stream. Chevron also learned, that this process is less expensive to install/operate and requires less space than the Stretford or the Amine methods.

If the fuel gas stream on Platform Grace would again show trace H_2S levels, Chevron's own FerriCat contactor system could be implemented as a back-up measure. The FerriCat technology also uses an iron-based chelate chemistry but, unlike the SulferOx process, it is applied in a non-regenerative manner, and it fits applications with less H_2S content.

SulferOx waste appears to be compatible with the other production waste streams for disposal through National Pollutant Discharge Elimination approved discharge points (NPDES). The desulfurization process is relatively simple: (1.) The sour gas is pretreated to be stripped of hydrocarbons; (2.) The dry gas is pumped through various cooler, separator, filter and heater stages before the stripped gas is processed through a gas contactor unit; (3.) Sweet gas is collected, while the SulferOx solution is flashed to remove any trapped hydrocarbon vapors which are returned into the vapor recovery unit; and (4.) The flashed solution enters the regenerator train. Elemental sulfur settles in the bottom slurry and the regenerated solution re-enters the cycle.

Design parameters:	**Plf. Gail:**	**Plf. Grace:**
Oil Production:	8,000 BOPD	1,000 BOPD
Gas Production:	18 MMSCFD	1,000 MSCFD
Low Pressure Flare:	0.6 MSCF/hr	16 SCF/hr
High Pressure Flare:	1.2 MSCF/ hr	805 SCF/hr
Turbine Fuel Gas:	64 MSCF/hr	37.6 MSCF/hr
SO_X	631 lbs/hr	396 lbs/hr

The project did not involve significant structural reinforcement of the deck structure. Total weight is comparable to an equivalent amine unit of equal or less capacity.

8. Platform Irene (Torch Operating Co.)

The operator had to find a technique to desulfurize produced gas to be flared in large volumes. The footprint and the weight of the unit were also critical on the already crowded platform (Table 2). The unique solution to fit these criteria was designed by Martech International, Inc. The system, under normal operating conditions, sweetens the produced gas stream from 3,000 ppm to less than 700 ppm H_2S before sending it to the flare up to 180,000 SCFHr, in compliance with local SO_X restrictions. The peak sweetening rate can cover routine operating events, such as scheduled vessel blow-downs, pig launching, well maintenance, and inspection.

The technology employs a closed-loop sweetening plant consisting of a small, low pressure scrubber/injector unit and of a large, high pressure scrubber/injector unit coupled with a sophisticated Mist Eliminator. A liquid chemical absorbent (Sulfa-Check) is injected into the incoming gas stream. The small scrubber/injector treats constantly 45 SCFH for the pilot light and base flare. Large gas kicks are sent to a 3-way diverter valve that opens into the large scrubber/injector unit. Here, the sour gas stream is injected into the SulfaCheck tower, it is stripped of H_2S, processed through the Mist Eliminator, and burned at the flare. The spent absorbent is recovered, blended into the produced oil-emulsion pipeline, and pumped onshore for separation and treatment. A multigas analyzer monitors the proper H_2S concentration and adjusts the spray density to avoid wasteful overdosing of the expensive chemicals. If the H_2S concentration is high, instead of being sent to the flare, the gas is pumped back for a second treatment. During our recent inspection, the H_2S reading was 0.0 to 1.0 ppm.

Torch applies smokeless flare technology and flare minimization plan. The pilot and base flare flow rates (45 SCFH) with the purge volumes average 707 SCFH. The maximum treated flare volume is 180,000 SCFH.

Most of the electricity is supplied to the platform via underwater cable from the shore by Pacific Gas & Electric Co. The Motor Control Center (MCC) supplies power to critical equipment such as fire water pumps and to the control system, if shore power should fail. Primary oil emulsion and water separation takes place on the platform and transported via pipeline to the nearest refinery. The platform's current production rate is 11,000 BOPD; 58,000 BWPD; and 6,500 MSCFD of sour gas. The new desulfurization system has been operating without major breakdown since 1994.

The advantages of this technology consist of small footprint, limited headroom; light load; no waste product storage on the platform, and the accommodation of fluctuating gas volumes with variable H_2S concentrations. Unlike most of our platforms, there is no vapor recovery system on Platform Irene. Vapors from all pressure vessels are collected and reinjected into the gas gathering system for dehydration, compression, and shipment to onshore. Total annual SO_X

emission from the platform is 10.74 tons/year.

Design parameters for Platform Irene:
Flare rate (planned, scenario#1): 400 MSCFD.
Produced gas maximum H_2S: 3,000 ppm.
Flare gas permitted H_2S: 796 ppm.
Maximum volume flared: 2,800 MMSCF/yr.

Suggestions and Conclusions

When choosing a desulfurization method, the following steps should be considered (see table 3): (1.) Determine the expected maximum daily gas volume and peak H_2S concentration, and select a number of methods reasonably fitting these criteria alone; (2.) Eliminate those processes that would not comply with platform specific limiting factors such as the maximum deck load on the available footprint, reduced storage capacity, total acid gas content of raw gas and absorber pressure/ temperature of the future contactor. (3.) Check the "Best Available Control Technology" recommended by the county Air Pollution Control Districts: it may not be compatible with the "Best Available & Safest Technology" compatible with installed platform processes[3]. (4.) Go to table 4.

We suggest to proceed in two stages and start with the outline in table 3. When the steps for the selection process in table 3 have been completed, half of the originally considered methods should have already been eliminated. Once the list of methods is reduced to a handful of candidates, the engineer should look at the sales line restrictions dictated by contractual agreements and by local laws: the maximum CO_2 slippage, minimum BTU content, and combined sweet gas requirements as throughput limitation factors (table 4).

From this point on the specific needs dictate the further selection process (deck storage space, transportation, etc.). For example, if the platform is far away from shorelines it may be desirable to inject produced sulfur slurry into the oil emulsion line to avoid deck storage, or look for alternatives like regenerative processes. Platforms closer to the shore can depend on weekly boat trips to off-load the spent chemicals and produced sulfur and may find these methods economical. Deck reinforcement maybe necessary, but the proper sensor and leak detection monitoring is a must. The final stage of selection should involve the in-depth analysis (Table 4).

Finally, here are a couple of specific suggestions for old platforms; (1.) First, try to computerize the whole desulfurization process to avoid waste of expensive chemicals; and (2.) If there is an amine unit installed, compare expensive desulfurization concepts to some Combined Amine[4] Process. Try to improve the existing method by the combination principle (less expensive, easier to install). One example is the combination of dietanolamine (DEA) with methyldiethanolamine (MDEA). The combined technology yields better capacity/efficiency, cleaner gas, and lower CO_2 levels than only one method alone. In this case the primary amine is more reactive toward CO_2 than the secondary amine (MEA), which is more reactive than the tertiary amine (MDEA).

This is not a limiting factor since MDEA is far less corrosive than the other two, it reacts slowly with CO_2 at low temperature, and as an added advantage, it generates less reaction heat. MDEA is also selective toward H_2S in the presence of CO_2, because tertiary amines can not react directly with CO_2 to form carbamate. Therefore, if one needs to increase solution concentration without corrosion risks, one could simply add more MDEA into the solution. For more on this subject, please refer to the bibliography.

Bibliography:

1. *The South Coast Air Quality Management District regulates the greater Los Angeles area air basin industrial air emissions, including the corresponding offshore Federal waters. Quotations are from the 1992 edition permit manual.*
2. *The Santa Barbara and Ventura County Air Pollution Control Districts (APCD) have very similar air emission restrictions, for both onshore and Federal water air emissions. However, in Northern Santa Barbara County, where Platforms Irene, Harvest and Hermosa operate the sulfurous emission limits are slightly different than the Southern County. We are quoting from the 1994 edtion of the two County Permit anuals and from permits granted in August and September of 1994.*
3. *Best Available & Safest Technology: see 30 CFR 250.22.(b); Federal Register, 1992, 1993, and 1994 edition.*
4. *Michael Spears, Kathy Hagan et. al.: "Converting to DEA.\/MDEA Mix Ups Sweetening Capacity. Paper to the "75th Annual GPA Convention", March 11-13, 1996, Denver, CO. (Oil & Gas Journal, Aug. 12, 1996, pages 63-67).*

Abbreviations:

APCD	*Air Pollution Control District (county office);*
BACT	*Best Available Control Technology;*
BAST	*Best Available & Safest Technology;*
BOPD	*on barrel = 42 U.S. gallons/day;*
BPD	*barrels per day (U.S.);*
BWPD	*barrels per day (U.S.);*

Clean Diesel Fuel: *less than 0.5% Sulfur by weight;*
Clean Fuel Gas: *gas sweetened to given sulfur content;*
DEA *diethanolamine (generic);*
DGA *Diethanolglycolamine (generic);*
DOI *U.S. Department of Interior;*
DOT *U.S. Department of Transportation;*
EPA *U.S. Evironmental Protection Agency;*
KCFPD *see also: 1 MCFD;*
LT *light ton, U.S.;*
MCFD *1,000 Standard Cubic Foot per Day;*
MSDS *Material Safety Data Sheet;*
NPDES *National Pollution Discharge Elimination System*
OCS *Outer Continental Shelf;*
LLC *Limited Liability Company*
MDEA *methyldiethanolamine (generic);*
MMS *Minerals Management Service, U.S. DOI;*
MMSCFD *Million standard cubic foot/ day;*
Pacific OCS *Offshore Federal waters in California;*
ppm as SO_x *parts per million, as SO and* SO_2*;*
ppmv *parts per million by volume;*
ppmvd *parts per million by volume, dry;*
SCAQMD *South Coast Air Quality Management District (Los Angeles air basin);*
SO_x *SO and* SO_2 *combined mass;*
SCFHr *standard cubic foot per hour;*
SRU *Sulfur Recovery Unit;*
STV *Sales Line Transfer Vessel Compressor;*
SWEPI *Shell Western Exploration & Production, Inc. (Since 1994: CalResources, LLC.)*

Conversions:
15 gr/100 scf *239 ppmvd, here as* H_2S*;*
1 lb *0.4536 kg;*
1 ppm H_2S *0.893 lb/MMSCF;*
1 SCF *1 standard cubic foot =* $0.0283\ m^3$*;*
1 U.S. gallon *3.7854 liter;*
1 U.S. barrel *42 U.S. gallons;*
°API *API gravity (of crude oil);*
°API =(141.5/Rel.)-131.5
Rel. = gram/cm³ (if density of water = 1.0 g/cm³);

Table 1 - Platform Characteristics

Platform	**H2S** (ppm)	**Volume** (MCFD)	**Sulfur** (t/yr)*	**Method**	**Comment**
Ellen-Elly	60	1,600	12	Sulfa-Check	Non-Toxic
OS&T** ('94)	18,000	97**	205	Sulfa-Check	Removed
Harmony	8,000	29,000	---	MDEA-Amine	To Pipeline
Heritage	2,990	36,000	---	MDEA-Amine	Re-Injected
Harvest	14,000 27,000	11,000 (5,000)	---	DGA-Amine	To Pipeline (diluted)
Hermosa	14,000	10,000	---	DEA-Amine	To Pipeline
Gail &Grace	8,000	19,000	630	SulferOx	Regen.
Irene	3,000	5,000	10.7	Sulfa-Check	To Pipeline

Note:
* *Sulfur expressed as either elemental sulfur or* SO_x*;*
** *OS&T had been decommissioned/ removed in April, 1994.*

Table 3 - Method Selection, Round #1:	
Process Issues:	**Platf. Characteristics:**
H_2S (ppm); Max. MCF/Day Safety vs. BACT: Desulf. Criteria Contaminants, Mercaptans Cost of Permitting: Emission Controls; Energy Demand	Avail. Deck Footprint Max. Load/ Footprint/ Future Expansion On-Deck Storage of: Raw Chemicals: Elem. Sulfur/ Disposal/ Distance to Shore

Table 2 - Platform Irene

API°	H2S (ppm)	MCFD (1996)	Sweet gas H2S (ppm)	Technology	Year
16-23	700-3,600	6,500	300-700	SulfaCheck	1994

Table 4 - Method Selection, Round #2:	
Process Selection:	**Gas Line Criteria:**
Regenerative or Spent? Toxic Waste Disposal; Sulfur vs. SO_X; Chemical Usage/Day? Process Poisoning; Acid Gas Tolerance; Absorber/ Contactor P&T, etc. Recycle vs. Reinject?	Gas Line Capacity: BTU/SCF; CO2 Slippage; Dew Points: Min. P/ T, Precipitates, Corrosion, Water Temp. Maintenance: Pigging/ Repairs